An engineering solution for CO2 injection in saline aquifers

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Abstract

In this proposed CO_2 injection system, brine is extracted from the target storage aquifer by means of a lateral horizontal completion located near the top of the formation. It should be noted that the brine is not lifted to the surface. An Electrical Submersible Pump (ESP) is used to extract the brine and boost its pressure, before it is mixed with CO_2 that is injected down the vertical section of the well. The mixing takes place in the vertical section of the well below the upper lateral. The CO_2 – brine mix is then injected into the same formation through a lower lateral. A down-hole tool would be used to maximise agitation and contact area between CO_2 and brine in the vertical mixing section of the well, which may be tens to hundreds of metres long, depending on the thickness of the formation.

The advantages of this method are that there is little overall pressure increase, because CO_2 is mixed with brine extracted from the formation, and also the extracted brine is already at high pressure when it is mixed with the CO_2, greatly increasing the solubility of CO_2 and reducing the volume of brine required. Energy is not expended lifting the brine to surface nor is there any concern about handling large volumes of acidic brine in the surface equipment. In this study, in addition to the concept of the down-hole mixing (DHM) method which is presented, the application of the DHM method in a hypothetical storage site (Lincolnshire – Smith et al., 2012) is also examined. The calculations are performed to identify the optimum rates of water extraction and injection of dissolved CO_2 in brine.

Introduction:

Since the industrial revolution, the CO_2 concentration in the atmosphere has increased by 45% (Celia et al., 2015). At the current time, it is believed that carbon capture and storage (CCS) can play a significant role in reducing the increase in the CO_2 concentration in the atmosphere (Haszeldine, 2009). In the long term, several trapping mechanisms such as structural and stratigraphic trapping, residual trapping, solubility trapping and mineral trapping can be used to sequester supercritical CO_2 into the aquifers or depleted reservoirs (Benson and Cole 2008). Structural trapping to prevent upward migration of CO_2 is provided by a very low permeability layer, which is frequently a clay or shale layer, at the top of the storage formation. Safe long-term CO_2 storage has been one of the most important issues, in

terms of environmental damage that could be caused by leakage (Gasda et al., 2004; Nordbotten et al., 2005; Burton and Bryant 2009; Celia et al. 2011; Bachu and Celia 2009). Therefore long-term monitoring needs to be carried out (Mathieson et al., 2011), which increases the total cost of CO_2 storage.

Furthermore, due to the complexity of fully understanding the interface between caprock/aquifer, and the risk of CO_2 leakage through caprock as a result of pressure build-up at the interface between aquifer/caprock (Shariatipour et al., 2012, 2014; Newell and Shariatipour 2016), the development of novel methods in which CO_2 injected into aquifers does not migrate toward the interface is desirable. In this paper an engineering method for CO_2 injection in which CO_2 is dissolved in brine down-hole is presented. If we can minimize the vertical migration of CO_2 in the reservoir, then it increases the safety in terms of any possible leakage through existing fractures and faults or fractures arising due to CO_2 injection. Injecting dissolved CO_2 could not only prevent buoyant vertical migration of CO_2, but it could also lead to dissolved CO_2 sinking in the reservoir, as brine with dissolved CO_2 is denser (around 1%) than formation brine (Ennis-King and Paterson, 2003, Ennis-King et al., 2005, Riaz et al., 2006).

In many carbon capture and storage (CCS) research projects that have been published (Kumar et al., 2005; Burton and Bryant 2009; Anchliya et al., 2012 and more), one of the main concerns the authors have addressed is the security of CO_2 storage. Several engineering techniques have been suggested to reduce this risk which can be classified into three categories (Emami-Meybodi et al., 2015): subsurface dissolution, CO_2/brine surface mixing and CO_2/brine wellbore mixing.

The "inject low and let rise" strategy was proposed by Kumar et al., (2005) to enhance the subsurface dissolution. Some authors (Keith et al., 2005; Leonenko et al., 2006; Taku et al., 2007; Leonenko and Keith 2008; Hassanzadeh et al., 2009; Anchliya et al., 2012) have suggested injecting brine above the CO_2 plume to accelerate CO_2 dissolution in the aquifer. They proposed a system where a horizontal brine injection well is placed above a horizontal CO_2 injection well. The water-alternative-gas (CO_2 WAG) has been investigated to increase the solubility trapping by injecting CO_2 chased by brine in the aquifers (Qi et al., 2009; Cameron and Durlofsky, 2012; Zhang and Agarwal 2012, 2013).

A CO_2/brine surface mixing strategy (Figure 1) has been investigated by different authors (Burton and Bryant 2009; Eke et al., 2011; Zendehboudi et al., 2011; Cholewinski and

Lonenko 2013; Tao and Bryant, 2014). They showed that the surface dissolution facilities enhance CO_2/brine solubility. Hence, the CO_2-saturated brine stream could overcome the buoyancy force. Bergmo et al., (2011) showed that producing water from the aquifer while injecting CO_2 leads to a reduction in pressure both in the near well bore and throughout the field. Therefore, it is considered that a CO_2/brine surface mixing strategy could improve the effectiveness of CO_2 storage. Because injecting dissolved CO_2 eliminates free CO_2 in the aquifer, there is no buoyant rise of CO_2 towards the caprock. However, Burton and Bryant (2009) admitted that the surface dissolution method has some disadvantages in comparison to the standard CO_2 injection method. For example: many more injection wells and extraction wells are needed which raises the storage cost. In addition, as the CO_2 saturated brine is acidic, the surface facilities and injection wells need to be resistant to corrosion. Furthermore, the cost of surface mixing equipment and related operations needs to be considered.

A wellbore dissolution technique was proposed (Shafaei et al., 2012; Zirrahi et al., 2013a; Pool et al., 2013; Paterson et al., 2014; Sigfusson et al., 2015) to eliminate some of the disadvantages of the CO_2/brine surface mixing strategy. Shafaei et al., (2012) proposed a reverse gas lift method to inject CO_2 through the annulus and brine through tubing simultaneously. In their proposed method, gas lift valves provide communication for CO_2 to access the tubing where water was injected and consequently CO_2 dissolves in brine in the wellbore. Zirrahi et al., (2013) performed laboratory experiments to assess the feasibility of a static mixing device for CO_2 and brine. They assume that the brine will be produced to the surface from a well some distance away. Then this water will be pumped into the tubing of the injection well while CO_2 is pumped into the annulus. The mixing device will be placed at the bottom of the injection well. Down-hole mixing of CO_2 and brine was performed in one of the tests at the Otway pilot storage site in Australia (Paterson et al., 2013). CO_2 and brine were injected simultaneously down the well, and no special mixing device was used. Sigfusson et al., (2015) demonstrated successful CO_2/brine wellbore dissolution process during its injection into porous basalts rocks at depth of 400-800 m at the Hellisheidi, Iceland CarbFix injection site. In all wellbore dissolution techniques that have been proposed the water is being injected at the wellhead and this means water needs to be extracted and lifted to the surface.

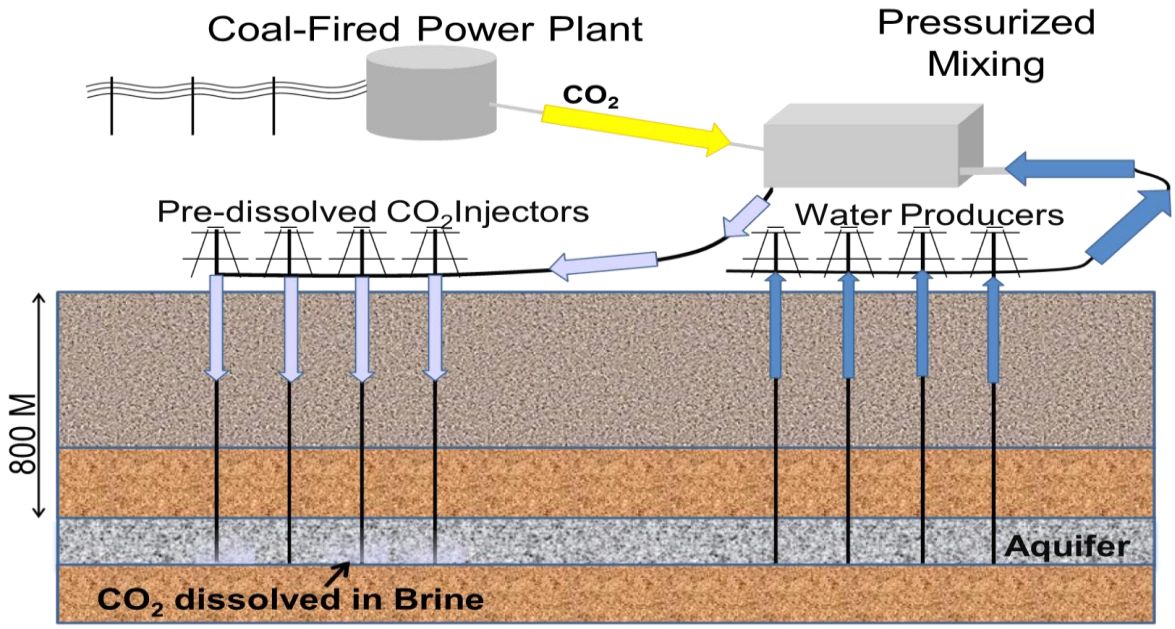


Figure 1: CO_2/brine Surface Mixing Strategy.

Methodology:

The aim of this work is to investigate the potential to increase storage capacity and security by use of an engineering method for CO_2 injection in which CO_2 is dissolved in brine down-hole. The advantage of injecting CO_2 dissolved in brine is that it is denser than unsaturated *in situ* formation brine (approximately 10kg/m^3,Ennis-King and Paterson, 2003, Ennis-King et al., 2005, Riaz et al., 2006), and so will not migrate towards the surface as free phase CO_2 would. Therefore, in this approach, retention of CO_2 within a formation does not rely on the presence of an impermeable seal. Instead, all CO_2 injected as a dissolved phase will migrate downwards. This has three consequences. Firstly, a higher percentage of the pore volume becomes available for storage, and not just that part of the rock that is shallower than the spill point: this can increase the storage capacity of formations. Secondly, there are no concerns around the integrity of the caprock. Indeed, there is no requirement for a caprock to prevent vertical migration of CO_2 due to buoyancy. Thirdly, this means that many additional formations may become available as potential storage sites.

As mentioned above, CO_2 dissolution in brine at the surface prior to injection has been considered previously (e.g. Burton and Bryant, 2009). However, this postulated method of injection suffers from some technical limitations. Because the solubility of CO_2 in brine is limited at standard conditions, energy would be required to pressurise CO_2 and brine at the

surface prior to mixing to enhance solubility. The cost of such equipment, which would have to have an appropriate pressure rating, be made of corrosion resistant material (high chromium steel) and have capacity for dissolving in the order of thousands of tonnes of CO_2 per day, would be prohibitive. Also, in this method if the brine in not extracted from the storage formation because of the availability of sea water and to reduce the cost of drilling the brine extraction wells, then the volume of brine that would have to be injected in addition to the CO_2 would increase the reservoir pressure much more rapidly than during pure CO_2 injection, very severely restricting storage capacity.

In this proposed injection system, brine is extracted from the target aquifer by means of a lateral horizontal completion located near the top of the formation (Figure 2). It should be noted that in this method water is not being lifted to the surface. An Electrical Submersible Pump (ESP) is used to extract the brine and boost its pressure, before it mixes with CO_2 that is being injected down the vertical section of the well. The mixing takes place in the vertical section of the well below the upper lateral. However, it should be noted that the entire volume of CO_2 may not be dissolved throughout the limited section of the wellbore. Blyton and Bryant (2013) studied the kinetics of CO_2 and brine under a range of conditions. They studied the dissolution throughout a 2000-ft wellbore for different wellbore radii. A down-hole tool (e.g. a static mixing device, Zirrahi et al., 2013a) would be used to maximise agitation and contact area between CO_2 and brine in the mixing section of the well, which may be 10s to 100s of metres long. The CO_2 – brine mix is then injected into the same formation in a lower lateral. If the CO_2 does not entirely dissolve in the wellbore the dissolution can continue inside the aquifer.

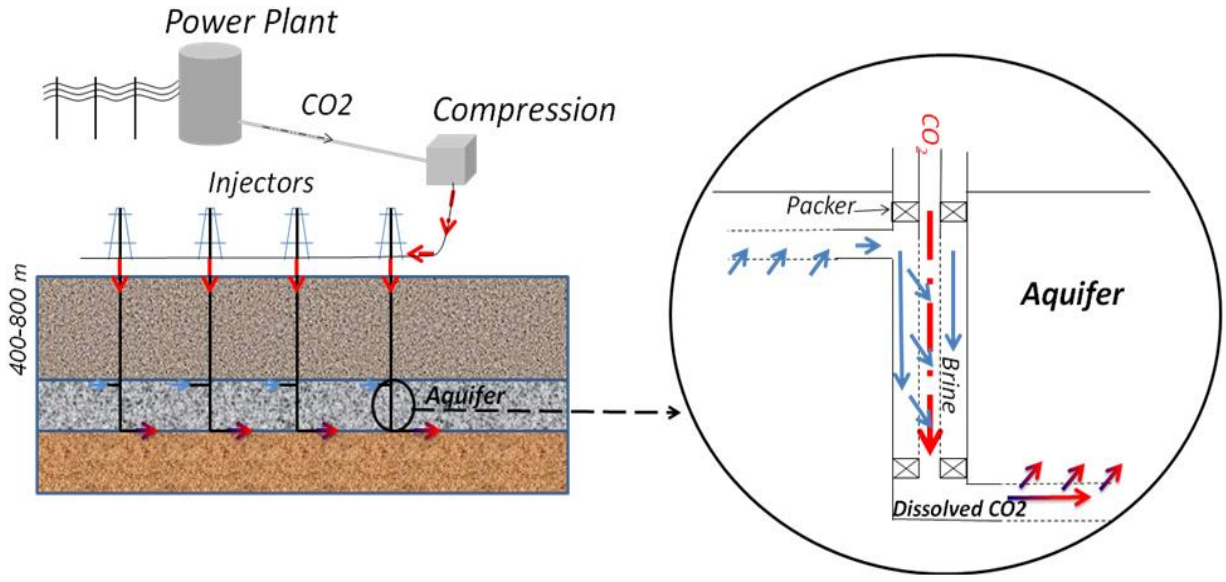


Figure 2: Schematic process of CO_2/brine down-hole mixing.

Dissolution of CO_2 in Brine

In this work, the method of Spycher and Pruess (2005) was used to calculate the mole fraction of CO_2 dissolved in brine (assuming that sodium chloride was the only salt present). They studied CO_2–H_2O mixtures in the geological sequestration of CO_2 at temperatures in the range 12–100 °C and at pressures up to 600 bars. CO_2 solubility in brine, at constant temperature and salinity, increases with increasing pressure within these ranges (Spycher and Pruess 2005). With increasing temperature, the solubility of CO_2 decreases even at increasing pressures. Thus the best conditions for having a greater dissolution of CO_2 in brine are higher pressure and lower temperature. Computed data shows that the optimum depth of CO_2 storage is just below 800 meters. On the one hand, pressure and temperature conditions meet CO_2 supercritical criteria at that depth. On the other hand, if CO_2 is stored at greater depth, the temperature and salinity will rise, so the amount of dissolution will decrease. It should be noted that storage of CO_2 in deeper saline aquifers with higher pressure and temperature have been of interest to several studies and they have been introduced as favorable candidates for CO_2 storage since storage in them is safer because they are deeper and also their geothermal energy and/or dissolved methane can be used to offset the cost of CCS (Ganjdanesh et al. 2014;2015; Salimi and Wolf, 2012).

Simulations of Down-hole Mixing

A range of numerical simulations using a variety of heterogeneous and homogeneous models was conducted to investigate the impact of the CO_2/brine down-hole mixing injection strategy. Eclipse 300 with the CO2STORE module (Schlumberger, 2012) was used for the simulations.

The models all have dimensions of 10000 m × 500 m × 134 m and were discretized into 200×50×80 cells. The porosity and the permeability values in the homogeneous models were assigned values of 0.2 and 1000 mD respectively in all directions. For the heterogeneous models the average porosity and average permeability values were the same as the homogeneous one. Sequential Gaussian simulation was used to generate the facies distribution and the permeability and porosity were correlated accordingly. The models represented part of a larger aquifer, and the pore volume of the ten outer cells on each side (left and right of the model) was multiplied by a factor of 1000, to take account of this. In the simulations, the pump for extracting the brine was modelled as a producer in one branch of a

well. The down-hole dissolution was not modelled explicitly. Instead, in the simulation, a solution of CO_2 dissolved in brine was injected through the lower branch of the well. In the subsequent description, these branches of the well are referred to as the producer and the injector.

In all cases, a single production/injection well was placed in the centre of the model. The composition of the injected fluid, in terms of mole fractions was 0.015, 0.9556 and 0.0294 for dissolved CO_2, water and NaCl respectively. These values correspond to thermodynamic equilibrium at down-hole conditions in the simulations, at 100 bars and 35 °C using Spycher and Pruess (2005). The control mode for both production and injection was reservoir fluid volume rate and the rates were 1000 rm^3/day and 940 rm^3/day for the injector (solution of CO_2 dissolved in brine) and the producer (brine) respectively. Both producer and injector were shut after 20 years and the simulation was continued for 100 years. It should be noted that the mineral trapping is not been considered in this modelling.

Figure 3 illustrates the well location and connections. Water is extracted from the top of the reservoir and pumped into the bottom hole while the supercritical CO_2 is injected into the well. Supercritical CO_2 is dissolved in the extracted brine in the well. It is assumed that this process can be managed by a specific CO_2/brine down-hole mixing tool.

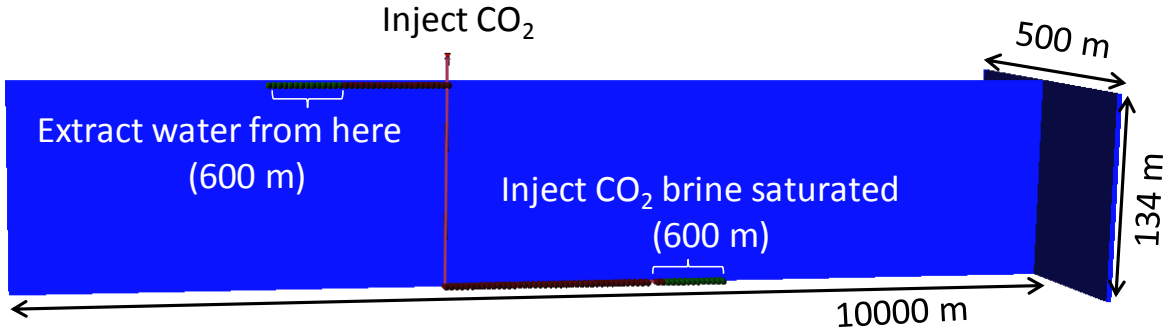


Figure 3: Well location and Connections.

This work does not consider the design of such a tool, but is purely concerned with the question of whether such a tool, if it could be appropriately designed, would provide a benefit for CCS. Zirrahi et al., (2013b) proposed the application of a back flow cell model for the simulation of the supercritical CO_2 dissolution. In the Otway Pilot Test (Paterson, 2013), it was estimated that down-hole mixing would occur without the use of a specific tool.

Sigfusson et al., (2015) successfully demonstrated the complete dissolution of CO_2 into water during its injection into a storage formation. In our study we assume the CO_2 is dissolved in brine prior to its injection into the saline aquifer.

Results and Discussion:

Figure 4 shows the CO_2 mole fraction at the end of the 20 year injection period and 100 years after shut-in, for the 3-D homogeneous and heterogeneous models. Note that, because CO_2 was dissolved in brine in the well, there was no free injected CO_2 in the model, nor did any exsolve from solution during the period of the calculation. As the dissolved CO_2 is injected into the aquifer it moves in all directions. This migration is governed by the injection rate, heterogeneity, production rate and gravity forces during the injection period. When both producer and injector are shut, gravity is dominant. The CO_2-saturated region tends to be skewed towards the producer where the pressure is lower, but the dissolved CO_2 does not reach the extraction region.

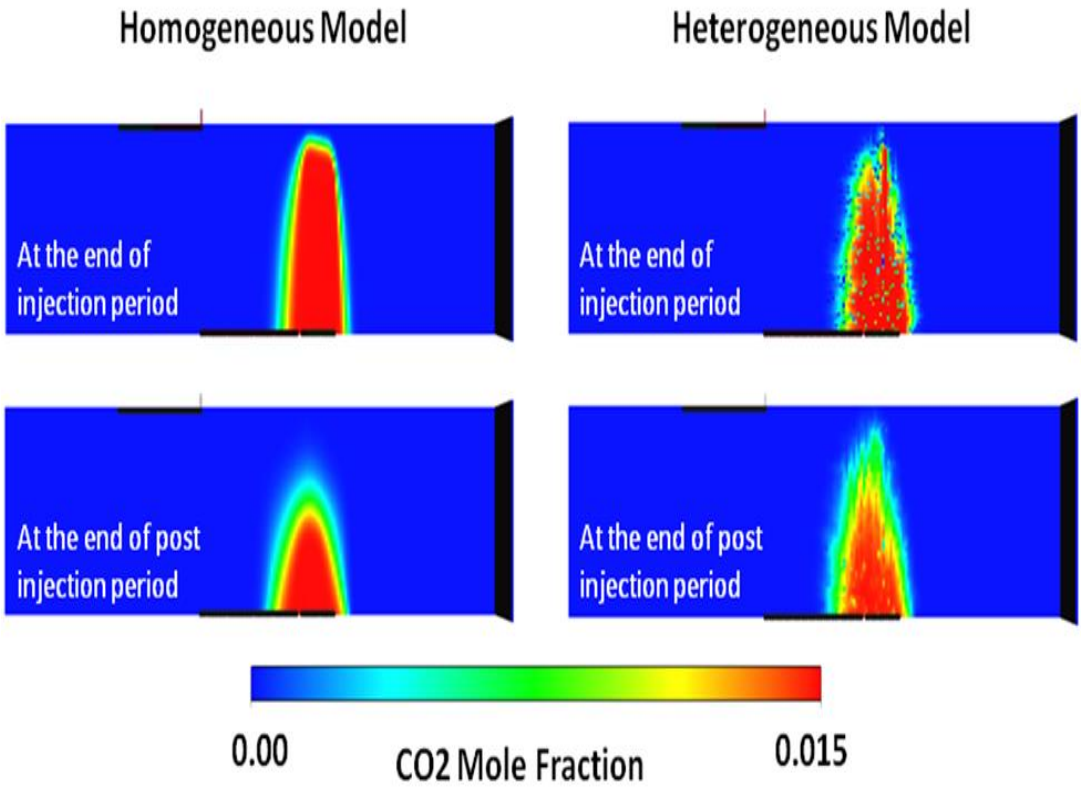


Figure 4: CO_2 mole fractions dissolved in brine in the X-Z plane for the homogeneous model (left) and heterogeneous model (right).

Figure 5 shows pressure changes across the aquifer in a cross section of the heterogeneous model. As can be seen the range in pressure in the model is only 25 bar. The time to establish a steady state pressure field is determined by the magnitude of the diffusivity constant. Once the transient period is completed, the subsequent pressure trends are determined by mass balance in the field, which depends on the difference between the down-hole injection and production rate.

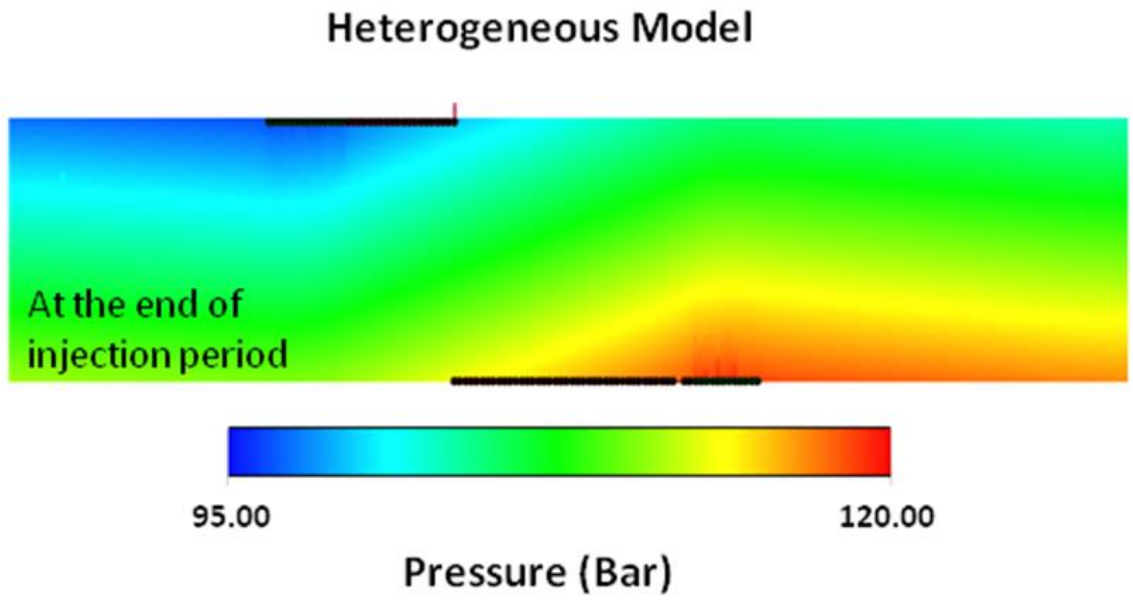


Figure 5: Pressure distributions in the X-Z plane at the end of injection period in the heterogeneous model.

The advantages of this method include

- Because the CO_2 is mixed with brine from the same formation, any overall pressure increase is due exclusively to injection of the CO_2 and is not due to brine.
- The extracted brine is already at high pressure when it mixes with the CO_2, greatly increasing the solubility of CO_2 and reducing the volume of brine required. Energy is not expended lifting the brine to surface. Nor is there any concern about handling large volumes of acidic brine in the surface equipment.
- The extent of monitoring of migration of free CO_2, which is costly, is decreased because all the CO_2 is dissolved.
- The injected CO_2 – brine mix will ultimately migrate downwards, increasing storage capacity and security.

Application of DHM Method to a Real Field

The British Geological Survey (BGS) highlighted a near shore formation in Lincolnshire as an analogue of a hypothetical large offshore storage site for captured CO_2 from potential onshore capture projects (i.e. Ferrybridge Power Station). A West to East schematic geological cross-section of the Lincolnshire study area is presented in the Figure (right picture).

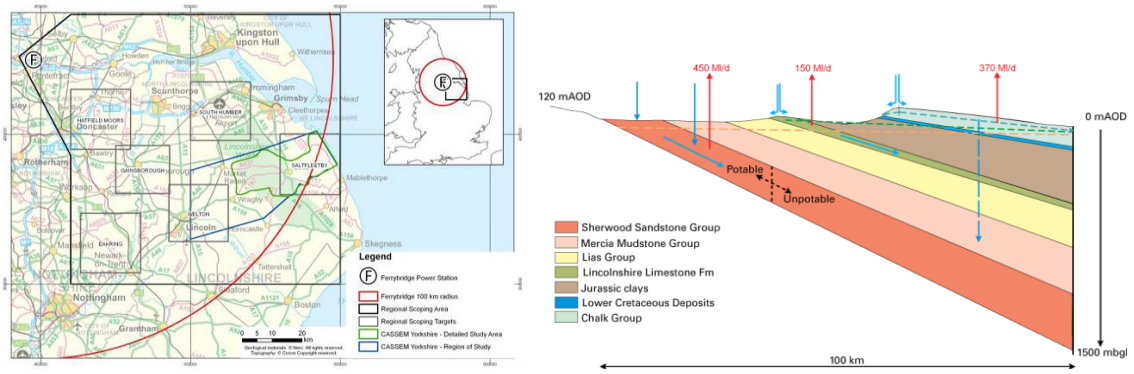
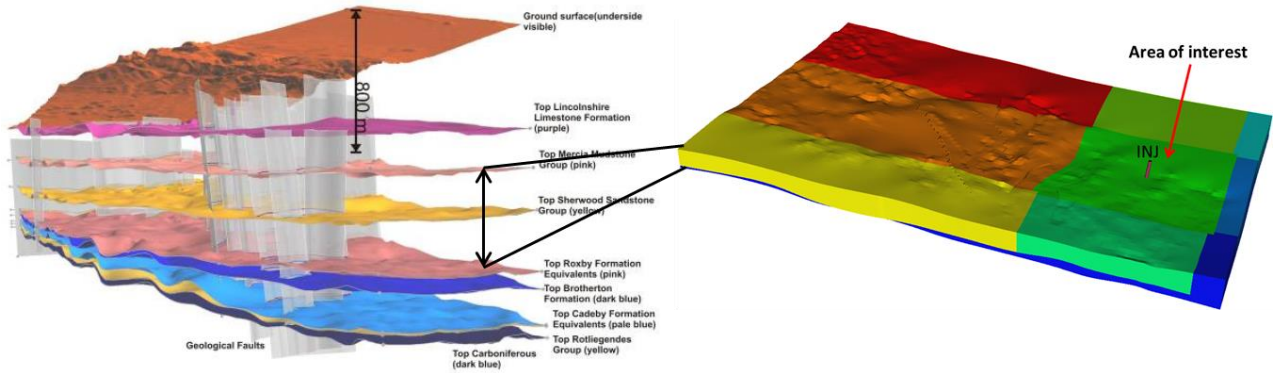


Figure 6 Location Map of Lincolnshire area (left picture), schematic geological cross-section (west to east) of the Lincolnshire study area (Smith et al., 2012).

The model has dimensions of 43 km × 33 km × 600 m and was discretized into 96×67×15 cells. An isotropic range of 2000m in the horizontal was used for the correlation in the distribution of properties. The geometric average for the permeabilities was 500 mD for the storage formation (Sherwood Sandstone) and 0.005 mD for the low permeable layers (Mercia Mudstone) (Smith et al., 2012). The ratio of vertical permeability to horizontal permeability (K_v/K_h) was assumed to be 0.1 due the layered types of sediments which were deposited in this region. The layer just beneath the caprock has been divided in 10 layers and modified to consist of 60% mudstone and 40% sandstone to represent the transition zone between the Sherwood Sandstone and the Mercia Mudstone, which was observed at outcrop (Shariatipour et al., 2014).

The base case model is large, covering an area of 1419 km^2 (top surface) and also has a large cell size 0.2 km^2 (450m×450m, in the X and Y directions). In order to improve the accuracy of the simulations, a sector of this model was used with a finer resolution. Figure demonstrates the area of interest for further study in this model.



306

307 *Figure 7 The geological framework of the Lincolnshire Model (10X vertical exaggeration)*
308 *(left picture, Smith et al., 2012), area of interest (green section) in the middle (right picture).*

309 In all cases, a single production/injection well was placed in the centre of the model (to
310 represent a down-hole mixing system, as described above). The control mode for both
311 production and injection was reservoir fluid volume rate and the rates were 6500 rm^3/day and
312 6175 rm^3/day for the injector and the producer, respectively. Both producer and injector were
313 shut after 100 years and the simulation was continued for 1000 years.

314 Figure 8 shows brine density verses depth used in the Lincolnshire Model for this study. As a
315 result of dissolving CO_2 in brine the density of brine increases (Duan and Sun 2003, Spycher
316 et al., 2005). This increase for the extracted brine at the depth of 1000 m in this model equals
317 7.8 kg/m^3 which is equal to the density of fresh brine at the depth of 2557 m. The difference
318 in density of brine with and without CO_2, for most suitable storage aquifers is similar.
319 However, the salinity gradient may vary and therefore the blue line may move upwards or
320 downwards.

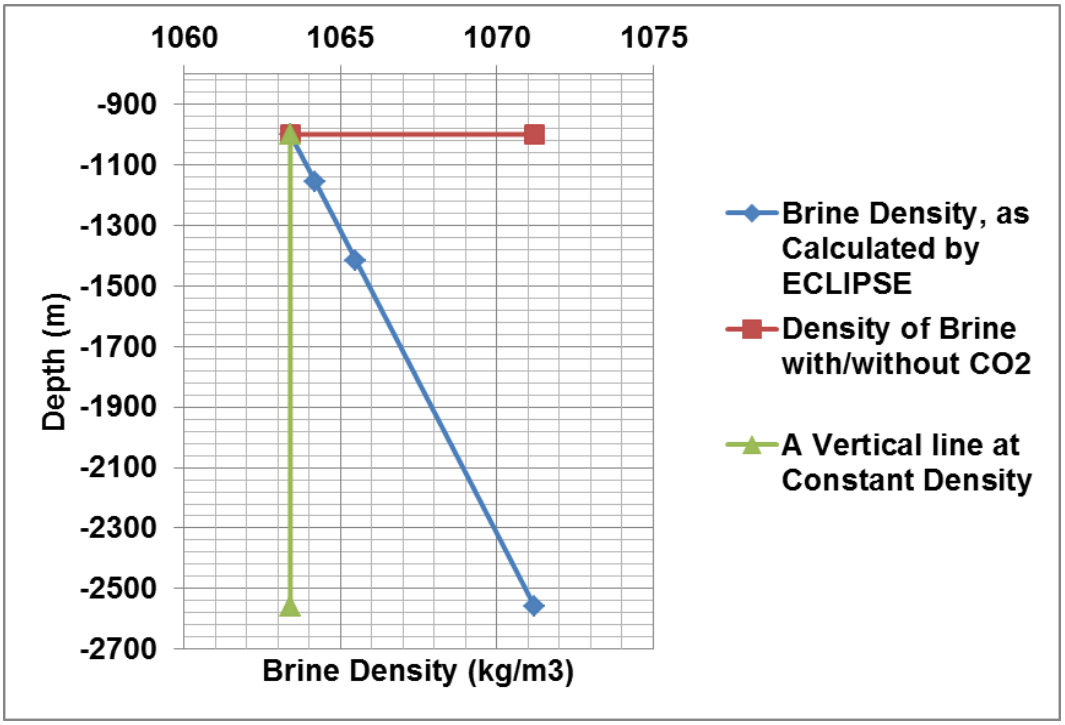


Figure 8 Brine density verses depth, red dots show density of brine without CO_2 (1063.4 kg/m^3) and with CO_2 (1071.2 kg/m^3) at the depth of 1000 m. The blue line refers to the brine density extracted from the simulator for the Lincolnshire Model. Geothermal gradient is set at 20 C/km.

Results

Figure 9 demonstrates the CO_2 mole fraction at the end of the 100 year injection period and 1000 years after well is shut-in. Note that, because CO_2 was dissolved in brine in the well, there was no free injected CO_2 phase in the model, nor did any exsolve from solution during the period of the calculation. CO_2 saturated brine is denser than *in situ* brine. Therefore, it should go downwards. Upwards migration of CO_2 occurs initially t due to the applied pressure gradient, but it then subsequently sinks down again due to gravity.

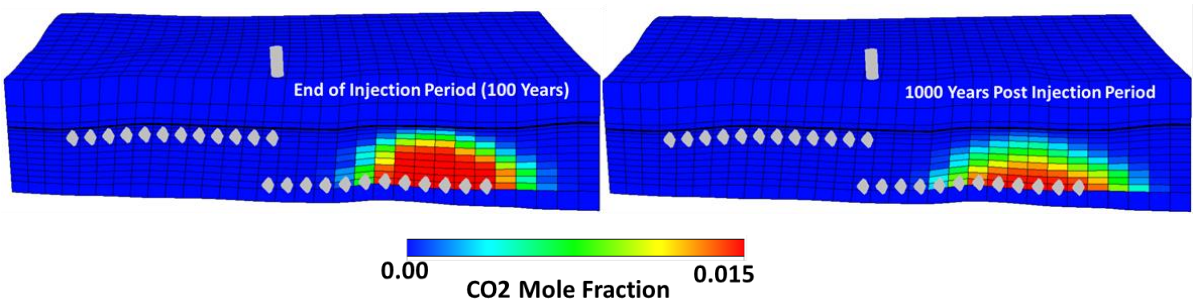


Figure 9 CO_2 mole fraction at the end of injection period (100 years) (left picture), and 1000 years post injection period (right picture).

Optimization

In this section we investigate the position of the laterals in terms of depths and lengths. *Table 1* and Figure 10 shows all scenarios studied here. The area around the injection lateral into which the dissolved CO_2 is injected was refined by factor of 9×9×9 in X, Y, and Z directions.

Table 1 Model properties

	Brine Extractor Lateral		**CO_2 Saturated Brine Lateral**	
Model	***Location of the lateral***	***Distance from the wellbore***	***Location of the lateral***	***Distance from the wellbore***
1	Top of the aquifer	2.7 km away from the wellbore	Bottom of the aquifer	2.7 km away from the wellbore
2	Top of the aquifer	2.7 km away from the wellbore	Bottom of the aquifer	Adjacent to the wellbore
3	Top of the aquifer	2.7 km away from the wellbore	Middle of the aquifer	2.7 km away from the wellbore
4	Top of the aquifer	2.7 km away from the wellbore	Middle of the aquifer	Adjacent to the wellbore
5	Top of the aquifer	Adjacent to the wellbore	Bottom of the aquifer	2.7 km away from the wellbore
6	Top of the aquifer	Adjacent to the wellbore	Bottom of the aquifer	Adjacent to the wellbore
7	Top of the aquifer	Adjacent to the wellbore	Middle of the aquifer	2.7 km away from the wellbore
8	Top of the aquifer	Adjacent to the wellbore	Middle of the aquifer	Adjacent to the wellbore

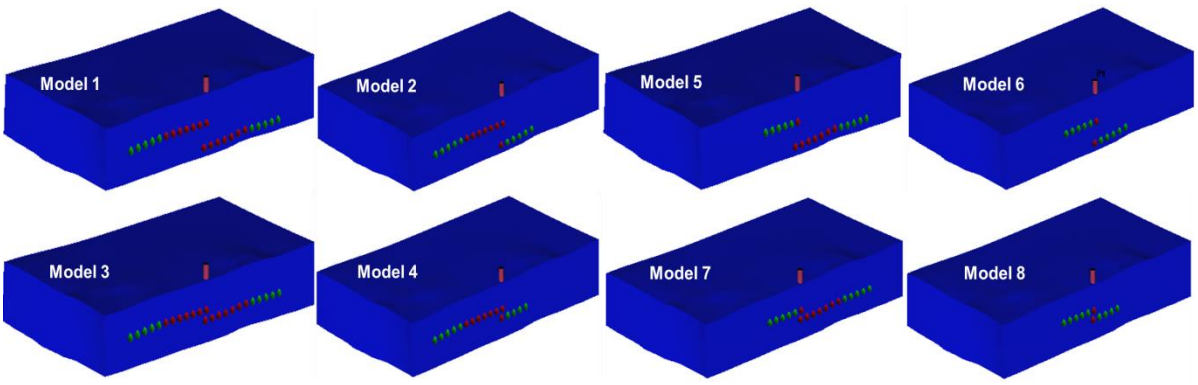


Figure 10 Cross sections of Models 1 to 8 show the brine extractor laterals at the top of the storage formation and the injector laterals at the either bottom of the aquifer (Models 1,2,5, and 6) or at the Middle of the aquifer (Models 3,4,7, and 8). Brine is extracted 2.7 km away from the well bore in the four left Models (1, 2, 3 and 4) whereas is extracted at adjacent to the well bore in Model 5, 6, 7, and 8 (four right models). Dissolved CO_2 in brine is injected into the storage formation 2.7 km away from the well bore in the four left Models (1, 3, 5, and 7) and at adjacent to the well bore in the four right Models (2, 4, 6, and 8) respectively.

The viscous force is the main driving force when dissolved CO_2 is injected into the aquifer. The injected fluid tends to migrate towards the brine extractor lateral where the pressure is lower. However, even after 100 years of dissolved CO_2 injection into the storage formation, the dissolved CO_2 does not reach the brine extractor perforations, except in Models 6 and 8 due to shorter distance between injection and producer points than in other models (Figure 11). All the free phase CO_2 was dissolved prior to injection into the storage formation. Dissolved CO_2 in brine is heavier than fresh brine and thus the CO_2 saturated brine tends to sink in the aquifer under gravity.

Models 6 and 8 are not of further interest due to the small distance between the perforation at the injector lateral and extractor lateral that could allow dissolved CO_2 to reach the extraction region. In all other models (1, 2, 3, 4, 5, 7) dissolved CO_2 does not reach the perforations at the extractor lateral. Therefore, all these models are acceptable for further study. However, further screening was performed based on the length of the laterals (which determines the cost), and the pressure loss. Model 1 provides the biggest distance between the extraction region and the injection region among all models, therefore it can be considered as the safest scenario. On the other hand, Model 4 could be the best option because of:

1. The lowest frictional pressure loss in the wellbore.
2. The minimum length of high chromium steel needed.

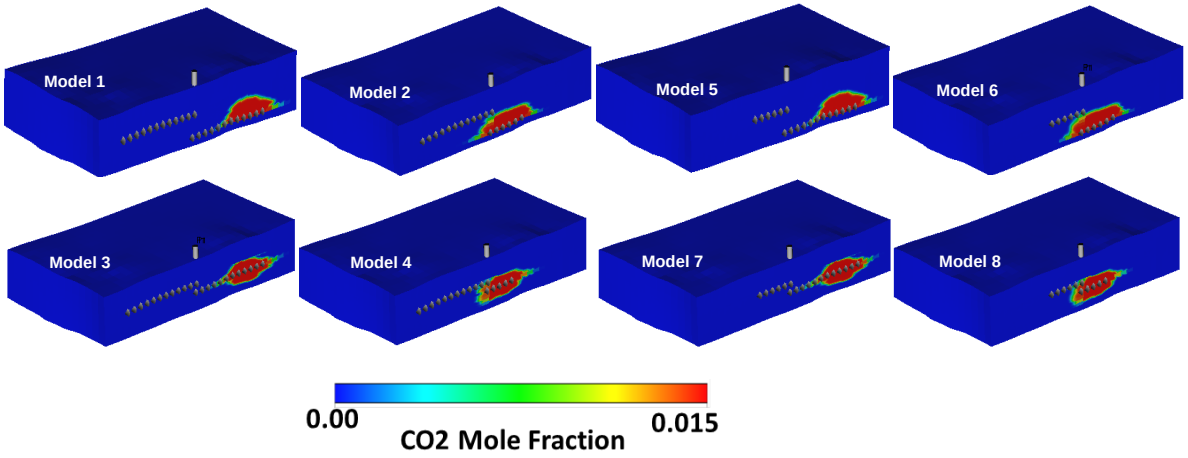


Figure 11 CO_2 mole fractions dissolved at the end of injection period (100 years). Models 1 to 8 show the brine extractor lateral at the top of the storage formation and the injector lateral at either the bottom of the aquifer (Models 1,2,5, and 6) or at the middle of the aquifer (Models 3,4,7, and 8). Brine is extracted 2.7 km away from the well bore in the four left Models (1, 2, 3 and 4) whereas it is extracted adjacent to the well bore in Models 5, 6, 7, and 8 (four right models). Dissolved CO_2 in brine is injected into the storage formation 2.7 km away in the four left Models (1, 3, 5, and 7) and adjacent to the well bore in the four right Models (2, 4, 6, and 8) respectively.

CO_2 Storage Capacity

Table 2 shows the amount of CO_2 can be dissolved in water with 3 different salinities (35000 mg/l, 100000 mg/l and 200000 mg/l) at depths of 1000 m. This analytical calculation is made based on Spycher and Pruess (2005).

Table 2: Amount of CO_2 which can be dissolved in brine at different conditions

Depth (m)	Pressure (bar)	Temperature (C)	Salinity (mg/l)	CO_2 dissolved (kg/m^3)
1000	100	35	35000	50.583
			100000	39.34
			200000	29.067

The density of CO_2 at 100 bars and 35 C equals 713.68 kg/m^3 and at standard conditions (15 C and 1 bar) equals 1.85 kg/m^3. In our calculation 39.34 kg CO_2 can be dissolved in 1 m^3 brine (NaCl, 100,000mg/l). Thus, the amount of CO_2 that can be dissolved at this reservoir condition in 6175 m^3 brine equals 242924.5 kg.

Assuming mass conservation, then 0.088 Mt CO_2/year per well can be dissolved down-hole and injected into the aquifer at the aforementioned condition. The target of injecting 1 MT CO_2/year can be achieved by drilling 11 wells. This calculation depends on the P, T, salinity, and the reservoir volume injection rate. For a reservoir with lower salinity (e.g. 35,000 ppm at the brine extractor points) with the same T, P, and reservoir volume injection rate just 8 wells are needed to inject 1 MT dissolved CO_2 in brine/year. Drilling engineering enables us to use dual completion and multi-lateral well techniques so more laterals could be used for brine extraction and CO_2 saturated brine injection. This results in reducing the number of required wells for CO_2 injection. The model indicates the amount of dissolved CO_2 which could be injected per well per year. However, at this stage, no detailed modelling of the mixing process in the well has been carried out.

The impact of injection of carbonated water would also be to stimulate the near wellbore, akin to acid stimulation (Fredd and Fogler, 1998), but on a continuous rather than batch basis. This would be different from any stimulation arising from pure CO_2 injection with subsequent dissolution in the brine phase, since such dissolution would, in the main, take

place away from the sand face. In this latter case, CO_2 would dissolve in the formation brine, and this acid brine will quickly be displaced from the near well zone, with less than one local pore volume of acid brine contacting the near wellbore rock. Any residual water would also be acidified, but any dissolution of rock would buffer this brine, and no further dissolution would take place. However, continuous injection of carbonated water will result in many multiple pore volumes of unbuffered acid brine flowing through the near wellbore zone, and this is the part of the system where rock dissolution and increase of local permeability will have the greatest impact.

Conclusions and Recommendations:

The results indicate that CO_2/brine down-hole mixing could improve CO_2 sequestration. This reservoir simulation study demonstrates that the upward migration of CO_2 in the reservoir can be limited to viscous effects during the injection period, and that during the subsequent shut-in period gravity segregation displaces the CO_2 saturated brine downwards, thereby increasing the storage safety. The limitation of the proposed method is that the amount of CO_2 that can be injected in one well is restricted. Injecting at a much higher total volume rate will increase the bottom hole pressure (BHP). On the other hand, it will be single rather than two-phase injection, and the acid brine may additionally stimulate the formation. The BHP will be higher for this method than if the CO_2 were injected without brine, but the increase will be somewhat mitigated by these two factors (single phase injection and acidic fluid stimulation). Also, the overall field average pressure will be the same as if the CO_2 were injected without brine, as the overall material balance is the same.

Calculations were performed to identify the optimum level and length of water extraction and injection of dissolved CO_2 in brine. In terms of the minimum length of corrosion-resistant tools and frictional pressure loss, the most efficient model is the one where the brine extraction lateral is completed away from the borehole whereas the CO_2 saturated injection lateral is close to the borehole. The former is to maximize the distance between extraction and injection and the latter is to minimize the need for having high chromium steel. This technique provides the opportunity for much more secure storage of CO_2 than is currently envisaged by conventional injection of CO_2 alone. Less attention needs to be paid to caprock integrity using this method of storage, and appraisal and monitoring costs may be vastly reduced. More secure storage of CO_2 will be of interest to organisations involved in CCS

projects, regulators, and other stakeholders, such as environmental organisations and the general public.

Having demonstrated that the concept can be used to maximise storage capacity and security, recommendations for future work include a full economic calculation to evaluate the use of a dual completion, instead of a new well, and also to compare economically this method with all other proposed methods for CO_2 injection.

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